STATE OF CALIFORNIA

ELECTRICITY OVERSIGHT BOARD

Gray Davis, Governor

April 9, 2002

Ms. Magalie Roman Salas, Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426

VIA EMAIL

Re: Electricity Market Design and Structure, Docket No. RM01-12-000

Dear Ms. Salas:

Please file the attached electronic version of the Comments of the California Electricity Oversight Board on Market Design Working Paper.

Thank you for your assistance.

Sincerely,

Sidney Mannheim Jubien

Sidney Mannheim Jubien
Senior Staff Counsel
Electricity Oversight Board

Enclosure

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Electricity Market Design and Structure	Docket No. RM01-12-000

COMMENTS OF THE CALIFORNIA ELECTRICITY OVERSIGHT BOARD ON MARKET DESIGN WORKING PAPER

The California Electricity Oversight Board (CEOB) offers the following comments on the Commission's "Working Paper on Standardized Transmission Service and Wholesale Electric Market Design" ("Working Paper"). The CEOB was created as a component of California's comprehensive restructuring legislation. The CEOB's statutory responsibilities include oversight of the California Independent System Operator Corporation (CAISO), the energy and ancillary services markets administered by the CAISO, and the reliability of the California electric grid.

The principal office of the CEOB is located at 770 L Street, Suite 1250, Sacramento, California, 95814. All pleadings, orders, correspondence and communications regarding this motion should be directed to the following persons:

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In its Working Paper, the Commission discusses a number of general principles and specific recommendations for modifying the existing pro forma open access transmission tariff (OATT), which was the outcome of Order Nos. 888 and 889, to correct perceived market-design flaws and to better integrate regional wholesale markets under a standardized set of rules.[1] In particular, the Working Paper embraces the Locational Marginal Pricing (LMP) system for pricing electricity and transmission service. Under LMP, an independent entity such as an independent system operator (ISO) or regional transmission organization (RTO) would operate the imbalance energy market and determine congestion charges based on the market clearing prices for electricity at each node on the grid. The CAISO has also embraced the LMP model for the future redesign of its real-time energy and congestion management markets as will be evident in the CAISO's May 1, 2002 filing on market reforms. California's energy agencies, including the CEOB, support this feature of the CAISO's market redesign effort. The CEOB also believes that the CAISO's market design proposal (referred to as "MD2002") is consistent with the market design elements included in the Working Paper.

I. COMMENTS ON GENERAL PRINCIPLES FOR STANDARD MARKET DESIGN

The CEOB offers comments on the first, sixth and tenth general principles. The Working Paper's first general principle explains that the "standard market design for wholesale electric markets is to establish a common market framework that promotes economic efficiency and lowers delivered energy costs, maintains power system reliability, mitigates significant market power and increases the choices offered to

[1] Much of the Working Paper is directed toward deficiencies of the pro forma OATT applicable to vertically integrated utilities. Since none of California's IOUs operates under the OATT, these comments do not address these issues.

wholesale market participants." Working Paper at 6. The first principle continues: "*All customers* should benefit from an efficient competitive wholesale energy market, whether or not they are in states that have elected to adopt retail access." *Id*. (emphasis added). While it cannot disagree with the desirability of all customers benefiting from an efficient competitive wholesale energy market, the CEOB doubts whether it is possible for all customers to benefit even if the Commission's goals are fully implemented. Some customers will likely pay more even if some customers pay less than they are paying today. The CEOB believes the main benefit RTOs might provide is lower total delivered energy costs as a result of gained efficiencies in the economic dispatch of regional resources, which would result in customers in high cost areas paying less while customers in low cost areas will pay more.[2] Moreover, this result assumes that these cost savings benefits would actually be achieved and that the cost savings would be passed on to end-users. As those of us in California and the Pacific Northwest well know, cost savings cannot be assured and profit-maximizing sellers will endeavor to retain the cost savings to increase their profitability.

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[2] In its April 9, 2002 comments on the Commission's February 26, 2002 "Economic Assessment of RTO Policy" prepared by ICF (RTO Policy Report), the CEOB points out that the economic assessment simply assumes that cost savings in a variety of categories will be achieved as a result of RTO formation rather than analyzing the potential for cost savings. In addition, many of the costs saving categories are not directly tied to the existence of an RTO. For example, improvements in generator efficiency ($34.7 billion) and peak load reduction ($19.1 billion) can be obtained by other means including existing incentives to achieve greater profitability in addition to other regulatory incentives and retail rate programs. The only source for cost savings that can be tied directly to the creation of RTOs would be the ability for end-use customers in high cost areas to have access to lower cost energy and the ability of energy suppliers in lower cost areas to sell power to customers in higher cost areas. As found in cost benefit studies referred to in the RTO Policy Report, customers in higher cost areas could end up paying less but customers in low cost areas would pay more. For example, in its study of the northeast, assuming what is now PJM, the New York ISO and the New England ISO were merged into a single RTO, LECG found that customers in New York city would enjoy lower electricity prices while customers everywhere else would pay higher prices. RTO Policy Report at 20.

The Commission's sixth general principle proclaims that market rules should be "technology-and fuel-neutral" and that "intermittent supply sources should be able to participate fully in energy, ancillary services and capacity markets." The CEOB believes that these two goals are incompatible. In order for intermittent supply sources to participate fully in the various energy markets, there will likely need to be some accommodation in applicable market rules. For example, in Amendment No. 42, the CAISO proposed to allow intermittent resources to offset their positive and negative deviations allowing them to avoid penalties for schedule deviations. The Commission approved this feature of Amendment No. 42 in its March 27, 2002 Order (98 FERC ¶ 61,327) in docket No. ER02-922. Since intermittent resources include wind and solar power, there are sound public policy reasons for encouraging intermittent resources and reasonable allowances should be made to allow them to participate.

The CEOB would also like to comment on the Commission's tenth general principle. This principle provides that customers with existing contracts should continue to receive the same level of quality of service under the standard market design. The CEOB believes that this principle is inconsistent with the Commission's overall goal of achieving a "seamless transmission grid with streamlined operations." Working Paper at 1. Existing transmission contracts (ETCs) include individually tailored scheduling rights that in many cases allow parties to schedule very close to and, in some cases, even during, the hour in question. Consequently, ETCs will limit the amount of capacity made available to other market participants in the day-ahead scheduling process thereby increasing the likelihood of phantom congestion and underutilization of the transmission system.[3] While it is entirely understandable that existing contract holders would not want to see their rights altered, unless ETCs are converted from existing rights to firm transmission rights (FTRs) that would subject all market participants to the same scheduling protocols, the benefits the Commission hopes to realize cannot be achieved. Similarly, a "seamless transmission grid with streamlined operations" cannot be achieved unless the ISO or RTO controls all the transmission system including assets owned by all transmission-owning utilities including those owned by publicly owned utilities (POUs).[4] These constraints reduce the potential for costs savings thereby reducing any potential for the benefits of the Commission's RTO policy to exceed the costs.

II. MARKET DESIGN AND MARKET POWER MITIGATION

The Commission places a great deal of faith on the benefits of good market design. No doubt, good market design is better than poor market design, but good market design will not prevent the exercise of market power. As much as the CEOB believes that the LMP system is superior to a zonal pricing model, the CEOB does not believe that LMP would have prevented California's electricity disaster. Market power monitoring and market power mitigation will, thus, be crucial.

With respect to market monitoring, the Working Paper recommends focusing on two general areas: (1) identifying design problems to be corrected before the exercise of market power becomes significant and sustained; and (2) monitoring market behavior, specifically, the physical and economic withholding of power. The CEOB believes an

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[3] Existing contract rights have created efficiency problems in the CAISO. Reserving transmission capacity for existing contract rights holders that is not then used causes "phantom congestion" generating congestion charges when the line is less then fully loaded.

[4] In order for POUs to be willing to join an ISO or RTO, any remaining private use tax issues must be resolved and, more importantly, the benefits of joining must exceed the costs without simply shifting the costs to existing participating transmission owners. The CAISO's transmission access charge proceeding in ER01-2019 has stalled over this extremely difficult cost-benefit issue.

important element is missing here: the price element and the Commission's responsibility to ensure just and reasonable rates. The Commission's responsibility is not to oversee markets; it is to protect consumer welfare. Markets are appropriate only insofar as they are a means to the end of just and reasonable rates. Accordingly, the CEOB supports market power mitigation measures such as the PJM and New York ISO bid mitigation mechanisms that are triggered when prices get too high—regardless of the reason. The CAISO is proposing to include a bid mitigation approach similar to the New York ISO's Automatic Mitigation Procedure along with damage control price caps that prevent excessive prices.

These kinds of objective triggers are especially important given the challenges posed by defining and then finding either physical or economic withholding. While it is entirely appropriate to design the market and its rules to minimize incentives to withhold, the Commission should not allow itself to get caught up in a futile effort of requiring a finding of market power abuse before it can impose mitigation. We hope this is one of the lessons that the Commission has learned in the last two years as a result of the California experience. California had nearly a year of excessive prices before the Commission took appropriate corrective action. If existing mitigation measures are not working to keep prices just and reasonable, then the Commission must take swift action to prevent continuing harm.

Of course, for markets to provide consumer benefits, flaws have to be fixed and loopholes have to be closed. The message the CEOB wants to drive home here is that when the Commission is confronted with prices that are excessive, the Commission must mitigate first; investigate second; and implement corrective measures third.

A. General Principles for Market Mitigation

In the first instance, the CEOB agrees that the market structure and its rules should be designed to prevent market participants from exercising market power. Given the existence of load pockets, congestion and the fact that summer peaks on extremely hot days can outstrip reasonable capacity margins, opportunities to exercise market power will remain. Thus, the CEOB takes issue with the Commission's fifth general principle (Working Paper at 22), which provides that "[m]arket rules should not require offers to sell below marginal opportunity costs of a unit, including verifiable geographic opportunity cost of selling to other regions and the temporal opportunity cost of selling energy-limited resources in other time periods." If opportunity costs are influenced by price expectations resulting from the exercise of market power, then sellers must and should be required to sell below such marginal opportunity costs.

In addition, allowing sellers to bid temporal opportunity costs would require the Commission to be able to distinguish between presumably legitimate scarcity rents and illegitimate exercises of market power. As noted above, the CEOB believes that the Commission should stick to objective cost and price benchmarks and not get caught up in the debate over scarcity rents.[5]

[5] It is doubtful whether these concepts can be meaningfully distinguished in the context of a real-time spot energy market. In the context of a fine art auction, scarcity rents are defined by what a bidder is willing to pay for a unique object. In a commodity market, sellers start raising their prices if a shortage is perceived. Buyers respond by buying less, buying a substitute or by agreeing to pay higher prices. Again, the demand side is deeply involved in determining the quantity purchased and the price paid. In a real-time electricity market, even if real-time demand response is integrated into this market, there will always be a need for an ISO or RTO to buy energy to keep the lights on when no particular buyer has agreed to pay the price. For this reason, there will always be need for a damage control cap at the very least.

B. Mitigation Measures

As discussed above, in addition to the market mitigations mentioned in the Working Paper at 23, bids should be mitigated based on objective cost and price factors.

C. Market Monitoring

The Working Paper states that the independent market-monitoring unit (MMU) should "report directly to the Commission and the independent governing board of the RTO." Working Paper at 23. Although the Working Paper generally acknowledges the need for, and importance of, state participation in the formation and operation of RTOs, the Working Paper ignores the legitimate need for state regulatory authorities to be provided with the same information. It is the end-users—the citizens of the affected states—that ultimately must pay for wholesale costs. The Commission should recognize this fact and require the MMU to report to appropriate state regulatory authorities.

III. REDISPATCH COSTS, CONGESTION CHARGES AND THE PRICE SIGNAL FOR TRANSMISSION EXPANSION

The Working Paper does not clearly define how congestion charges are determined. In several instances, the Working Paper refers to "congestion costs" as the costs to redispatch a more expensive generator due to lack of sufficient transmission capacity for load to be served by a cheaper resource. Working Paper at 9. Elsewhere, the Working Paper equates the "cost of transmission congestion" to the "opportunity cost of having too little transmission," a rather Delphic phrase that might refer to redispatch costs, the energy clearing price at the more expensive transmission constrained area, or the cost of the transmission upgrade to alleviate the constraint. Working Paper at 4. Clearly, the Commission must give much more attention to congestion management if congestion charges are intended to serve as an important price signal for locating new generation and transmission upgrades. As discussed below, congestion charges are distinct from the redispatch costs incurred to relieve congestion and may not be an efficient price signal for building new transmission.

Redispatch costs and congestion charges are distinguishable. Advocates of LMP generally define the congestion charge as the difference between locational energy prices between nodes.[6] For example, ignoring losses, suppose a $35 per MWh 300 MW generator at node A (Gen A) bids (or schedules) all of its capacity to serve 300 MW of load at node B, but that the available transmission capacity between nodes A and B is limited to 250 MWs. There is a $40 generator at node B (Gen B) that will have to supply the additional 50 MWs of capacity. Using this example, the LMP at node A is $35 per MWh and the LMP at node B is $40 per MWh. The congestion charge would be $5 per MWh and Gen A would be charged a total of $1,250 per MWh (5 x 250). The actual redispatch cost in this example, however, is only $250 (5 x 50). The point of this example is to illustrate that the congestion charge is simply a defined charge rather than a cost based charge and is, in fact, unrelated to the actual redispatch costs incurred to relieve congestion. Moreover, load pays the redispatch costs in the form of energy payments. Revenues from congestion charges, on the other hand, are paid to holders of FTRs. In our example, if Gen A had FTRs for 250 MWs of capacity, then congestion charges would be entirely offset by congestion revenues.

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[6] This may be what is intended at page 10 by the following sentence: "A locational energy price equals the delivered cost of electricity to that point, which equals the sum of the energy price plus its congestion cost plus the value of transmission line losses from the source to the sink."

The most economically efficient point at which to invest in new transmission is when the redispatch costs exceed the amortized cost of new transmission.[7] Yet, the redispatch costs are not reflected in a transparent way. If only one megawatt had to be redipatched the total cost would be $5. If 50 megawatts need to be redispatched, the total cost is $ 250. Yet the only transparent prices are the energy price at node B and the $5.00 per MWh congestion charge. The congestion charge, on the other hand, which is transparent, is an inefficient price signal for new investment in transmission since the congestion charge can greatly exceed the redispatch costs. Moreover, avoidance of transmission charges is unlikely to provide sufficient investment incentive for market participants to build new transmission without guaranteed cost recovery.[8]

The role of congestion management/charges and FTRs is to provide a market mechanism for allocating existing transmission capacity. The proposed market regime allows market participants to compete for access either by purchasing FTRs or by agreeing to pay congestion charges up to a certain level. Gen A should be willing to pay up to $5.00 per MWh in the form of congestion rents assuming sufficient competitive pressure from other suppliers.

IV. DAY-AHEAD MARKET FEATURES

The CEOB generally agrees that the features and rules for the Day-Ahead market proposed in the Working Paper are appropriate and the CAISO's long-term market design encompasses most of these features. There are certain differences, however.

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[7] The $40 per MWh price at node B is also a price signal for new more efficient generation to locate at node B.

[8] Phillipe Auclair, "Financial Instruments in a Restructured California Electricity Industry: An Assessment," prepared for the August 14, 1996 ***ER 96*** Electricity Committee hearing of the California Energy Commission, July 17, 1996 at 9-10.

First, the Working Paper includes a requirement in the seventh principle (Working Paper at 14) that sellers be allowed to submit three part bids (start-up costs, no load costs and energy). The CAISO's proposed day-ahead market is for energy bids only. If there is insufficient uncommitted supply after the day-ahead market closes, the CAISO will then dispatch additional resources through a residual unit commitment market that requires three-part bids and allows for full cost recovery. The practical result should be the same in both the Commission's and the CAISO's market designs—allowing the CAISO to dispatch uncommitted resources while ensuring that these resources recover their costs.

The eleventh and twelfth principles deal with intermittent resources stating, on the one hand, that there may need to be scheduling options for these resources and, on the other hand, that intermittent resources should participate on the same basis as other resources. As discussed above, the CEOB believes that there should be scheduling options for intermittent resources, but that these options should not necessarily be available to all resources. For example, the CAISO's Amendment 42 allows intermittent resources participating in the CAISO's market to offset positive and negative schedule deviations against each other. The CEOB opposes similar treatment for other resources. Deviations from schedules have caused reliability problems and increased costs.

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V. CONCLUSION

The CEOB believes that the LMP is a significant improvement in market design that should bring efficiencies and remove some gaming opportunities. That said, LMP will not eliminate market power and objective cost-based mitigation measures will need to remain in place for the foreseeable future and beyond.

Dated: April 9, 2002

Respectfully submitted,

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CERTIFICATE OF SERVICE

I hereby certify that I have caused the foregoing document to be served upon each person designated on the official service list compiled by the Secretary for this proceeding on April 9, 2002, pursuant to Rule 2010(a) of the Commission's Rules of Practice and Procedure.

Dated at Sacramento, California, this 9th day of April 2002.

/s/
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